217/782-2113

CONSTRUCTION PERMIT - NSPS SOURCE - NESHAP SOURCE - REVISED

PERMITTEE

Marathon Ashland Petroleum LLC
Attn: John Swearingen
100 Marathon Avenue
Robinson, Illinois 62454

Application No.: 03030085 I.D. No.: 033808AAB
Applicant's Designation: Date Received: June 15, 2005
Subject: Gasoline Desulfurization Unit Project
Date Issued: September 13, 2005
Location: 100 Marathon Avenue, Robinson

This Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of a Gasoline Desulfurization Unit (GDU) project, that is, various changes to the refinery to produce lower sulfur gasoline, as described in the above-referenced application. This Permit is subject to standard conditions attached hereto and the following special condition(s):

1.0 Unit Specific Conditions

1.1 Unit: GDU Project

1.1.1 Description

The proposed project will allow the refinery to produce lower sulfur gasoline, as required by the USEPA Tier 2 gasoline sulfur requirements. Reduced sulfur in the fuels will be accomplished by installing a new Gasoline Desulfurization Unit (Unit 74) and upgrading the amine regeneration facilities in the Amine Treating Unit (Unit 9). These modifications will not result in an increase in crude throughput.

The new Gasoline Desulfurization Unit will require hydrogen to operate. The refinery currently has the hydrogen capacity to operate the Gasoline Desulfurization Unit.

The sulfur recovery units will experience an additional loading of sulfur due to the incremental sulfur removed in the new Gasoline Desulfurization Unit. The sulfur recovery units currently have sufficient sulfur production capacity to handle this increased loading.

The existing sour water stripper is adequate for any new loading.

1.1.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
74	New Gasoline Desulfurization Unit	None
74F-1	New Gasoline Desulfurizer Feed Heater	None
74F-2	New Gasoline Desulfurizer Reboiler	None
Unit 9	Existing Amine Treating Unit Modifications	None
Fugitives	Fugitive Emissions from New Components Associated with the GDU Project	None

1.1.3 Applicability Provisions and Applicable Regulations

a. The "affected heaters" for the purpose of these unit-specific conditions are the fuel gas combustion devices (74F-1 and 74F-2) listed in Conditions 1.1.1 and 1.1.2.

i. A. This permit is issued based upon the affected heaters being subject to the NSPS for Petroleum Refineries, 40 CFR 60 Subparts A and J. The Illinois EPA administers the NSPS for subject sources in Illinois pursuant to a delegation agreement with the USEPA.

B. The Permittee shall not burn in the affected heaters any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf) [40 CFR 60.104(a)(1)].

ii. A. The Permittee shall not cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from the affected heaters except as provided below [35 IAC 212.123(a)].

B. The emission of smoke or other particulate matter from the affected heaters may have an opacity greater than 30 percent but not greater than 60 percent for a period or periods aggregating 8 minutes in any 60 minute period provided that such opaque

emissions permitted during any 60 minute period shall occur from only one such emission unit located within a 305 m (1,000 ft) radius from the center point of any other such emission unit owned or operated by such person, and provided further that such opaque emissions permitted from each such emission unit shall be limited to 3 times in any 24 hour period [35 IAC 212.123(b)].

iii. The Permittee shall not cause or allow the emission of carbon monoxide (CO) into the atmosphere from each affected heater to exceed 200 ppm, corrected to 50 percent excess air [35 IAC 216.121].

b. This permit is issued based upon the Gasoline Desulfurization Unit (No. 74) being subject to the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, 40 CFR 63 Subparts A and CC. The Illinois EPA administers the NESHAP for subject sources in Illinois pursuant to a delegation agreement with the USEPA. The Permittee shall comply with all applicable requirements of 40 CFR 63, Subparts A and CC.

c. This permit is issued based upon the Gasoline Desulfurization Unit (No. 74) being subject to the NSPS for Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems, 40 CFR 60 Subparts A and QQQ. The Illinois EPA administers the NSPS for subject sources in Illinois pursuant to a delegation agreement with the USEPA. The Permittee shall comply with all applicable requirements of 40 CFR 60, Subparts A and QQQ.

d. i. This permit is issued based upon the Sulfur Recovery Plant (Unit Nos. 62 and 63) being subject to the NSPS for Petroleum Refineries, 40 CFR 60 Subparts A and J. The Illinois EPA administers the NSPS for subject sources in Illinois pursuant to a delegation agreement with the USEPA.

ii. The Permittee shall not discharge into the atmosphere from the Sulfur Recovery Plant any gases containing SO_2 in excess of 250 ppm by volume, dry basis, corrected to zero percent excess oxygen [40 CFR 60.104(a)(2)(i)].

1.1.4 Non-Applicability of Regulations of Concern

a. This permit is issued based on the affected heaters not being subject to 40 CFR 60 Subpart Dc, NSPS for Industrial-Commercial-Institutional Steam Generating Units because they are not steam generating units, i.e., they are considered process heaters.

b. The source has addressed the applicability and compliance of 40 CFR 52.21, Prevention of Significant Deterioration (PSD) (See Attachment 1). The limits established by this permit are intended to ensure that the modification addressed in this construction permit does not constitute a major modification pursuant to this rule.

i. This permit is issued based upon an increase of 1.0 tons VOM per year attributable to an incremental increase in material stored in storage tank(s) during unscheduled shutdown of the Gasoline Desulfurization Unit.

ii. This permit is issued based upon an increase of 0.1 tons H_2S per year attributable to an incremental increase in loading of sulfur into tank cars.

iii. This permit is issued based upon increases in emissions from the steam boilers 59F-3 through 59F-6 as follows:

Pollutant	Emissions (Tons/Year)
NO_x	57.7
CO	28.3
VOM	1.8
PM/PM_{10}	1.7

iv. This permit is issued based upon increases in emissions from the flares, attributable to emergency releases from the GDU, as follows:

Pollutant	Emissions (Tons/Year)
NO_x	0.1
CO	0.5
VOM	0.2
SO_2	0.2

v. This permit is issued based upon an increase of 1.7 tons SO_2 at the Sulfur Recovery Units attributable to an incremental increase in sulfur feed rates to the Sulfur Recovery Units.

1.1.5 Operational and Production Limits and Work Practices

a. i. The affected heaters shall be equipped, operated, and maintained with low NO_x burners. These burners shall be operated and maintained in conformance with good air pollution control practices.

ii. The firing rate of the affected heaters shall not exceed the following:

Heater	Firing Rate (mmBtu/Hr)*
Gasoline Desulfurizer Feed Heater (74F-1)	29.6
Gasoline Desulfurizer Reboiler (74F-2)	99.1

* Limits are based on a HHV and 12-month rolling average.

iii. Only gaseous fuels shall be burned in the affected heaters.

b. i. These requirements, and the emission limitations in Condition 1.1.6, become effective following completion of the GDU Project when the refinery first begins to process low-sulfur gasoline for commercial sale.

ii. Provided the Permittee complies with testing requirements specified in Condition 1.1.7, operation of the new and enhanced units addressed in this permit is allowed until final action is taken on the source's CAAPP permit under this construction permit.

1.1.6 Emission Limitations

a. i. Emissions from affected heater 74F-1 shall not exceed the following limits:

Pollutant	Emissions (Ton/Mo)	(Tons/Year)
NO_x	0.9	5.4
SO_2	0.6	3.6
CO	1.2	6.7
VOM	0.2	0.7
PM/PM_{10}	0.2	1.0

ii. Emissions from affected heater 74F-2 shall not exceed the following limits:

Pollutant	Emissions (Tons/Mo)	(Tons/Year)
NO_x	3.0	18.0
SO_2	2.1	12.2
CO	3.7	22.4
VOM	0.5	2.5
PM/PM_{10}	0.6	3.4

iii. These limits are based on information in the application, including a NO_x emission rate of 0.040 lbs/mmBtu, HHV (See also Condition 1.1.12(b)).

b. i. Emissions of VOM from the new* components (i.e., valves, pumps, flanges, etc.) associated with the GDU Project shall not exceed 32.2 tons per year.

* This limit does not address components that are already present at the refinery with the existing process units.

ii. Emissions of SO_2 from the GDU attributable to catalyst sulfiding shall not exceed 2.9 tons/month and 5.8 tons/year.

c. i. Emissions of VOM from the components (i.e., valves, pumps, flanges, etc.) associated with the Sulfur Recovery Plant shall not exceed 1.1 tons per month or 6.4 tons per year. For the purposes of this permit term, the Sulfur Recovery Plant shall include the Sulfur Recovery Units (Units 62 and 63), the TGTU (Unit 66, including the amine tank), and the Sulfur Recovery Plant Thermal Oxidizers (Units 66F-3 and 66F-5).

ii. The TGTU amine storage tank shall be vented to a carbon canister, which shall be replaced as needed.

d. Emissions from the Sulfur Recovery Plant Thermal Oxidizers, which include Units 66F-3 and 66F-5, shall not exceed the following limits (limits are for both units combined):

Pollutant	Emissions (Tons/Mo)	(Tons/Year)
NO_x	2.6	15.1
SO_2	12.5	74.6
CO	2.0	11.5
VOM	0.2	0.8
PM/PM_{10}	0.2	1.1

e. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

1.1.7 Testing Requirements

a. Hydrogen Sulfide Testing

In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the affected heaters will be operated, but not later than 180 days after initial startup of the affected heaters and at such other times as may be required by the Illinois EPA, the Permittee shall conduct performance test(s) in accordance with 40 CFR 60.106(e) and furnish the Illinois EPA a written report of the results of such performance test(s).

Note: The hydrogen sulfide testing requirement is not necessary if the H_2S content of the fuel gas to the affected heaters is monitored by an existing CEM.

b. Nitrogen Oxides Testing.

i. Within 60 days after achieving the maximum production rate at which the affected heaters will be operated, but not later than 180 days after initial startup, the NO_x emissions of the affected heaters shall be measured during conditions which are representative of maximum emissions.

ii. The following methods and procedures shall be used for testing of emissions, unless another method is approved by the Illinois EPA: Refer to 40 CFR 60, Appendix A, for USEPA test methods.

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2
Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
Nitrogen Oxides	USEPA Method 7

1.1.8 Monitoring Requirements

a. The Permittee shall comply with the monitoring requirements specified in 40 CFR 60.105 for the affected heaters by installing, calibrating, maintaining and operating either of the following continuous monitoring systems:

i. An instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere from each affected heater. The monitor shall include an oxygen monitor for correcting the data for excess air; or

ii. An instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in the affected heaters.

b. For the affected heaters, the Permittee shall determine compliance with the H_2S standard in 40 CFR 60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration in the fuel gas. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line [40 CFR 60.106(e)(1)].

c. For the affected heaters, the Permittee shall maintain records of the following items to demonstrate compliance with Condition 1.1.3(a)(i)(B):

i. For a SO_2 monitor: a record of the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere; or

ii. For a H_2S monitor: a record of the concentration (dry basis) of H_2S in fuel gases before being burned in the affected heaters.

d. The Permittee shall comply with the monitoring requirements specified in 40 CFR 60.105 for the Sulfur Recovery Plant by installing, calibrating, maintaining and operating continuous emissions monitoring systems to continuously monitor and record emissions of SO_2 from the Sulfur Recovery Unit Thermal Oxidizers (measurements on each of the stacks (Nos. 1 and 2)) [40 CFR 60.105(a)(5)].

1.1.9 Recordkeeping Requirements

a. The Permittee shall maintain records of the following items for the affected heaters:

i. Firing rate of the affected heaters (mmBtu/hr on a 12-month rolling average, based on higher heating value);

ii. Heat content of the fuel gas (Btu/scf); and

iii. NO_x, CO, VOM, SO_2, PM and PM_{10} emissions from the affected heaters (tons/month and tons/year), as determined by methods in Condition 1.1.12(b).

b. For the boilers (59F-3 through 59F-6), storage tanks used to store material during unscheduled shutdown of the Gasoline Desulfurization Unit, and the Sulfur Recovery Units (for SO_2 emissions only):

i. Before beginning actual construction of the project, the Permittee shall document and maintain a record of the following information [40 CFR 52.21(r)(6)(i)]:

A. A description of the project;

B. Identification of the emissions unit(s) whose emissions of a regulated PSD pollutant could be affected by the project; and

C. A description of the applicability test used to determine that the project is not a major modification for any regulated PSD pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions

excluded under paragraph (b)(41)(ii)(c) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

ii. The Permittee shall monitor the emissions of any regulated PSD pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in 40 CFR 52.21(r)(6)(i)(b) (See also Condition 1.1.9(b)(i)(B)); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit that regulated PSD pollutant at such emissions unit [40 CFR 52.21(r)(6)(iii)].

c. The Permittee shall maintain records of the following items for fugitive emissions from components:

i. Number of new components by unit or location and type in the GDU Project; and

ii. Calculated VOM emissions including supporting calculations, attributable to these components (tons/year), based on the methods in Condition 1.1.12(c).

d. The Permittee shall maintain records of the Sulfur Recovery Unit SO_2 emissions on a daily basis (tons/month and tons/year), as determined by continuous monitoring in accordance with Condition 1.1.8(d).

1.1.10 Reporting Requirements

a. The Permittee shall notify the Illinois EPA of deviations of the affected heaters with the permit requirements as follows. Reports shall describe the probable cause of such deviations, and any corrective actions or preventive measures taken.

b. For affected heaters, the Permittee shall comply with the reporting requirements specified in 40 CFR 60.107(d), (e) and (f) and 40 CFR 60.105(e)(3).

c. For the boilers (59F-3 through 59F-6), storage tanks used to store material during unscheduled shutdown of the Gasoline Desulfurization Unit, and the Sulfur Recovery Units (for SO_2 emissions only), the Permittee shall submit a report to the Illinois EPA and USEPA if the annual emissions, in tons per year, from the project identified in 40 CFR 52.21(r)(6)(i) (See also Condition 1.1.9(b)(i)), exceed the baseline actual emissions (as documented and maintained pursuant to 40 CFR 52.21(r)(6)(i)(c), by a significant amount (as defined in 40 CFR 52.21(b)(23) for that regulated PSD pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to 40 CFR 52.21(r)(6)(i)(c). Such report shall be submitted to the Illinois EPA and USEPA within 60 days after the end of such year. The report shall contain the following [40 CFR 52.21(r)(6)(v)]:

i. The name, address and telephone number of the major stationary source;

ii. The annual emissions as calculated pursuant to 40 CFR 52.21(r)(6)(iii); and

iii. Any other information that the Permittee wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

1.1.11 Operational Flexibility/Anticipated Operating Scenarios

N/A

1.1.12 Compliance Procedures

a. Compliance with the particulate matter emission limitations specified in Condition 1.1.3(a)(ii) is considered inherent in the normal operation of an affected heater firing refinery fuel gas.

b. i. Compliance with the SO_2 limits in Condition 1.1.6(a)(i) and (ii) shall be based on the operating records required by Condition 1.1.9 and the sulfur content of refinery fuel gas as monitored in accordance with Condition 1.1.8.

ii. Compliance with the other emission limits in Condition 1.1.6(a)(i) and (ii) shall be based on the operating records required by Condition 1.1.9 and appropriate emission factors:

Pollutant	Emission Factor (Lbs/mmBtu, HHV)
NO_x	0.040
CO	0.050
VOM	0.0055
PM/PM_{10}	0.0076

When available, results from representative stack tests in accordance with the methods described in Condition 1.1.7(b)(ii) or in 40 CFR Part 60, Appendix A shall be used in lieu of these emission factors to represent actual emissions.

c. Compliance with the emission limits for VOM leaks in Condition 1.1.6(b)(i) and 1.1.6(c)(i) shall be based on the recordkeeping requirements in Condition 1.1.9 and applicable standard emission estimate methodology published by USEPA in "Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017 (November 1995).

d. i. Compliance with the SO_2 emission limits in Condition 1.1.6(d) for the Sulfur Recovery Unit is demonstrated by continuous monitoring.

ii. Compliance with the other emission limits in Condition 1.1.6(d) for the Sulfur Recovery Unit shall be based on the operating records required by Condition 1.1.9 and appropriate emission factors:

Pollutant	Emission Factor (Lbs/mmBtu, HHV)
NO_x	0.12, 0.10
CO	0.084
VOM	0.0055
PM/PM_{10}	0.0076

0.12 lb/mmBtu is the NO_x factor for Oxidizer No. 1. This NO_x emission factor is a site-specific emission factor determined from a stack test performed at the refinery (1994). 0.10 lb/mmBtu is the NO_x factor for Oxidizer No. 2 (constructed in 2001). This NO_x emission factor and factors for all other pollutants are standard applicable emission factors published by USEPA, AP-42, 5th edition, Section 1.4.

This permit has been revised to correct the baseline actual emissions for the sulfur recovery units and to change the method of calculating whether a significant increase in emissions has occurred. For this purpose, the Permittee will no longer be presuming that the projected actual SO_2 emissions are equal to the units potential to emit, and has instead made a specific determination of future actual emissions. As a result of this change, the project is now less than significant without the need to rely on contemporaneous emissions decreases.

If you have any questions on this permit, please contact Jason Schnepp at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:JMS:psj

cc: Region 3
Lotus Notes
Compliance and Enforcement Section

Attachment 1

PSD Applicability - NO_x Netting Analysis

Contemporaneous Time Period of August 1998 Through August 2003

Table I – Emissions Increases and Decreases Associated With the Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential* (Tons/Yr)	Emissions Change (Tons/Year)	Permit Number
74F-1 GDU Feed Heater	0.0	5.4	5.4	03030085
74F-2 GDU Reboiler	0.0	18.0	18.0	03030085
Flares (flaring of GDU emergency releases)	0.0	0.1	0.1	03030085
62F-1 & 63F-1 (SRU)	14.8	15.1	0.3	03030085
Boilers 59F-3 through 59F-6	329.0	386.7	57.7	03030085
		Total:	81.5	

* The listed value for the Boilers 59F-3 through 59F-6 represents projected actual emissions, not potential to emit.

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
Thermal Oxidizer	July 2001	7.1	01050067
Platformer	September 2002	32.0	02090015
	Total:	39.1	

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
Robinson Optimization Project	November 2001	51.0	99020080
Crude Asset Reliability Proj.	February 20002	89.8	01090064
	Total:	140.8	

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	81.5
Creditable Contemporaneous Emission Increases	39.1
Creditable Contemporaneous Emission Decreases	- 140.8
	- 20.2

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